TECHNICAL REVIEW DOCUMENT for OPERATING PERMIT 970PWE180

to be issued to:

Public Service Company - Ft. St. Vrain Station Weld County Source ID 1230023

Prepared December 1998 and March 1999 by
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Revised April, June, August and September 1999
Revised October 1999 as a result of comments received during the Public Comment
Revised November 1999 to address changes to 40 CFR Part 75, Appendix D

I. Purpose:

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. The conclusions made in this report are based on information provided in the original application submittal of February 18, 1997, supplemental information received April 23 and May 11, 1999, comments on the draft operating permit and technical review document received May 25, September 16, and October 21, 1999, a June 15, 1999 meeting regarding the May 25 comments and additional information submitted June 23 and August 26, 1999 to support agreements discussed in the meeting and various e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

On April 16, 1998 the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction Permits. These procedures are being directly implemented in all operating permits that had not started their Public Comment period as of April 16, 1998. All short term emissions and production/throughput limits that appeared in Construction Permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling 12 month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable

monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting hours of operation.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Source Description:

This source is classified as an electric services facility under Standard Industrial Classification 4911. This facility is a decommissioned nuclear power generation facility. Nuclear operations ceased at this facility in 1989 and decommissioning was completed in 1996. The repowering of this facility utilized a large portion of the non-nuclear assets such as the turbine (steam) generator, with a generating capacity of approximately 340 MW, the cooling water system, condensate and feed water system, water treatment systems, and a substation.

The repowered facility consists of two (2) natural gas fired combustion turbines and two (2) heat recovery steam generators (HRSG) to generate approximately 470 megawatts (MW) of electricity. The turbines are numbered as follows: Turbine No. 1/T001 (steam turbine), Turbine No. 2/T002 (combustion turbine No. 1) and Turbine No. 3/T003 (combustion turbine No. 2). Each combustion turbine generates approximately 135 MW of electricity and each HSRG, which includes duct burners for supplemental firing, will add approximately 100 MW of electricity. These combustion turbines and HRSG combinations can be run in three modes: simple cycle (combustion turbine only), combined cycle (combustion turbine with HRSG) with no fuel fired in the duct burners and combined cycle (combustion turbine with HRSG) with fuel fired in the duct burners. In simple cycle operation, exhaust from the combustion turbine is discharged through the bypass stack. In combined cycle, the exhaust gas from the turbine passes through the HRSG first and then exits out the HRSG stack. In addition to the combustion turbines, significant emission units at this facility consist of an auxiliary boiler fueled by natural gas and two cooling towers.

The facility is located approximately three miles north and west of Platteville Colorado. There are no affected states within 50 miles of the plant. Rocky Mountain National Park, Eagle's Nest National Wilderness Area and Rawah

National Wilderness Area, Federal Class I designated areas, are within 100 kilometers of the plant.

The area in which the plant operates is designated as attainment for all criteria pollutants. This source is a major stationary source for the purposes of Prevention of Significant Deterioration (PSD) with facility wide emissions as follows:

<u>Pollutant</u>	Potential to Emit (PTE), tpy	Actuals, tpy
PM	186.6	80.3
PM_{10}	128.7	29
SO ₂	9.6	1.6
NO_x^-	1,021.5	5.7
VOĈ	46.7	0.8
CO	955.4	14.5
HAPs	12.3	Negl.

Potential to emit is based on the emission limits identified in construction permits for those permitted units. In the case of unpermitted emission units, the potential to emit is based on the information provided in the Title V permit application. Actual emissions are based on the Air Pollution Emission Notices (APENs) submitted with the Title V permit applications (based on 1996 data). It should be noted that the No. 2 combustion turbine started up in January 1999 and the No. 1 combustion turbine was only minimally operated in 1996. The source indicated that this facility is subject to 112(r), the Accidental Release Requirements since chlorine gas storage exceeds threshold levels.

III. Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site. A. Units T002 & T003: Two (2) General Electric Combustion Turbines, Model No. GE Frame 7FA, Serial Nos. 296677 and 297096, Unit T002 is rated at 1773 mmBtu/hr and Unit T003 is rated at 1,823 mmBtu/hr, Natural Gas Fired.

These combustion turbines and HRSG combinations can be run in three modes: simple cycle (combustion turbine only), combined cycle (combustion turbine with HRSG) with no fuel fired in the duct burners and combined cycle (combustion turbine with HRSG) with fuel fired in the duct burners. Note that the above ratings, are for the combination of the turbine and duct burners.

- 1. Applicable Requirements Turbine No. 2 was first placed into service in February 1996 as a simple cycle turbine. The combined cycle capabilities became operational in March 1998. Turbine No. 3 began operation in January 1999 as a simple cycle turbine, with combined cycle operations beginning April 1999. Construction Permit 94WE609 PSD (initial approval, May 26, 1995) was issued for these units. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the initial approval construction permit was issued and/or the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification for construction permit 94WE609 PSD and the appropriate provisions of the construction permit have been directly incorporated into this operating permit. The following applicable requirements have been identified for these units:
- a. Best Available Control Technology (BACT) shall be applied for NO_X, CO, VOC and PM (condition 1). BACT shall be as follows:
 - 1) NO_X dry low NO_X (DLN) combustion system (condition 1):
 - A) DLN combustion chambers shall be upgraded to new versions emitting lower NO_{χ} emissions as they become available from the manufacturer, and in accordance with the manufacturer's recommendations for equipment replacement. The Division shall be kept apprised of these developments along with the manufacturer's guarantees as to the performance/emissions (condition 1).

A review of the file indicates that the original intent of the requirement was to require the source to use upgraded burners when replacement was required due to wear or manufacturer's recommendations. It is not the intent of the PSD requirements to

require that BACT technology be continually upgraded. Discussions with the construction permitting group indicates that the requirement to upgrade technology was part of the BACT analysis. However, this requirement is not practically enforceable and there is no guarantee that upgrading the low NO_X technology when necessary will result in a reduction in emissions (i.e. components may not be compatible). Therefore, this requirement will not be included in the operating permit.

B) Emission limitations in terms of concentrations per turbine in exhaust gases (condition 2a):

Avg. Hourly Ambient Temp. (°F)	Gross Load per Combustion Turbine (MW)	NO _x Concentration, at 15% O ₂ (ppmvd)	Maximum Hours per Combustion Turbine in any 12 month period ¹
below 0	less than 130	100	240
equal to 0 or above 0 and below 30	less than 105	100	520
equal to or greater than 30	less than 60	100	1,650
any temperature	any load	17 - combined cycle	8,760
		15 - simple cycle	
		25 - simple cycle*	

¹When both combustion turbines are installed and operational to total operating hours for T002 and T003 shall not exceed twice these operating hours.

At the end of each hour, the data shall be summarized to generate the minimum load that occurred during the hour and the hourly averages for the remaining values. If the minimum load for the hour is below the minimum load for the temperature range and the average corrected NO_X emissions are greater than 17 ppmvd at 15% O_2 , the operating time at this condition shall be logged against the appropriate operating condition.

In general, throughout construction permit 94WE609 PSD conditions and/or requirements are based on simple cycle operating mode versus combined cycle operating mode. Conversations with the construction

^{*} This limit is no longer in effect and will not be included in the operating permit, since it expires upon start-up of combined cycle (Combustion turbine No. 1began combined cycle operation in March 1998)

permit engineer indicate that the combined cycle mode was intended to describe the combustion turbine operating in conjunction with the heat recovery steam generator (HRSG) with fuel being fired to the duct burners. This makes sense from an engineering standpoint since one would not expect air pollutant emissions and/or fuel usage to be any different when the combustion turbine exhaust gases are routed to a HRSG rather than being directly emitted.

The operating permit will identify operating scenarios of simple cycle mode, combined cycle mode without fuel being fired in the duct burners and combined cycle mode with fuel being fired in the duct burners. Simple cycle mode requirements, as identified in Construction Permit 94WE609 PSD, will apply to the first two scenarios. Combined cycle mode requirements, as identified in Construction Permit 94WE609 PSD will apply only to the combustion turbine and HRSG combination when fuel is being fired to the duct burners.

The various bins for the NO_x limits at 100 ppm have been removed as the Division believes and the source agrees that BACT under normal operating conditions is the 15/17 ppm limits. The Divison has included a secondary BACT limit for startup and shutdown conditions. During these periods, the turbines cannot meet the 15/17 ppm BACT limitations. The secondary BACT limit for startup and shutdown has been set at 100 ppm. The source indicated in their August 26, 1999 submittal that during startup, emissions of NO_x generally range from 30 - 70 ppm and requested that BACT for startup and shutdown be set at 100 ppm. The Division is allowing the higher limitation as adequate startup and shutdown data may not have been available for the worst case (presumably a "cold" combined cycle startup during low temperatures) start up conditions. The Division believes that allowing the bin for startup and shutdown will not affect the quality of the air (i.e. NAAQS) as the NAAQS for NO_x is an annual average and the modeling performed to support the original PSD permit application (94WE609 PSD) was performed at 560.6 tons/yr per turbine and predicted emissions well below the NAAQS or PSD increments. Annual NO_x limits remain in the permit at 496.1 tons/yr, an annual limitation lower that the value that was originally modeled.

Finally, the requirement to monitor the minimum turbine load and the average temperature will not be included in the permit. Since the original BACT bins are being replaced with a startup/shutdown limit and normal operation limit, it is not longer necessary to record the average temperature of minimum load. Note that the requirement to monitor the operating condition of the turbine (i.e. startup, shutdown, or normal) will also not be included in the permit. The source indicated that it could be

determined, without the flag in the CEM, whether the unit was operating in startup, shutdown or normal operation. Although the Division will not require that operating mode be recorded on the CEM, the source will be required to maintain records of those periods of startup and shutdown.

- 2) CO Good combustion practices/monitoring systems (condition 1).
 - A) This system shall be maintained, operated and monitored according to the manufacturer's recommendations to ensure continued performance (condition 1).
 - B) Emission limitations in terms of concentrations per turbine in exhaust gases (condition 2b):

Temperature (∘ F)	Gross Load per Turbine (MW)	CO Concentration, at 15% O ₂ (ppmvd)
Any	Less than or equal to 135	None
Any	Greater than 135	48 - combined cycle
		15 - simple cycle

These combustion turbines are subject to BACT requirements for CO, which in this case is good combustion practices and the above emission limitations. The Division erred in issuing the PSD permit for this facility by exempting these combustion turbines from the BACT CO emission limitations at low loads. EPA guidance is clear that BACT emission limits apply at all times. The stack tests performed for turbine No. 2, demonstrate that the CO emission limitations can be met at low loads and therefore there is no justification, nor is it allowable per EPA guidance, for exempting these units from the BACT emission limits. Therefore, in the operating permit, the CO BACT emission limits will apply at all loads and at any temperature.

As previously discussed for NO_X , the Division believes and the source agrees that BACT under normal operating conditions is the 15/48 ppm limits. During startup and shutdown, the turbines cannot meet the 15/48 ppm BACT limitations. The Division will include a BACT limit of 1000 ppm and 2,060 lbs/hr during startup and shutdown conditions. The 1000 ppm was determined by converting the hourly limit to a ppm limit. Although the source indicated that during startup, emissions of CO generally range from 250 - 500 ppm, the Division is allowing the higher limitation as

adequate startup and shutdown data may not have been available for the worst case (presumably a "cold" combined cycle startup during low temperatures) start up conditions. The modeling performed to support the original PSD permit (95WE609 PSD) was evaluated at this hourly rate (2,060 lbs/hr) and predicted emissions to be less than the NAAQS (1-hour and 8-hour averages).

It is necessary to explain the 1000 ppm and 2,060 lbs/hr startup and shutdown BACT limit. The Division considers BACT limits to be in terms of ppm and not lbs/hr. However, since the hourly emission rate can vary depending on the ppm and the exhaust flow, the Division is including the lbs/hr limit in the permit as a part of the BACT limit. The lbs/hr limit is the emission rate these turbines were modeled and that limit must be met to ensure the NAAQS are protected. As a result, it should be noted that emissions that exceed 1000 ppm but are less than 2,060 lbs/hr are not considered a violation of the BACT limit. However emissions less than 1000 ppm but in excess of 2,060 lbs/hr are considered a violation of the BACT limit.

- 3) VOC Good combustion practices/monitoring systems (condition 1).
 - A) This system shall be maintained, operated and monitored according to the manufacturer's recommendations to ensure continued performance (condition 1).
 - B) Emission limitations in terms of concentrations per turbine in exhaust gases (condition 2c):

Temperature (∘ F)	Gross Load per Turbine (MW)	VOC Concentration, at 15% O ₂ (ppmvd)
Any	Less than or equal to 135	None
Any	Greater than 135	1.7 - combined cycle
		1.4 - simple cycle

These combustion turbines are subject to BACT requirements for VOC, which in this case is good combustion practices and the above emission limitations. The Division erred in issuing the PSD permit for this facility by exempting these combustion turbines from the BACT VOC emission limitations at low loads. EPA guidance is clear that BACT emission limits apply at all times. In general, the stack tests performed for turbine No. 2, demonstrate that the VOC emission limitations can be met at low loads. The first stack test (April/May 1996) performed on turbine No. 2 (simple cycle mode) indicated that the VOC limitations were exceeded at 25% load. However, the combined cycle stack test performed in June 1998 indicated that the VOC limitations were not exceeded at any load. The Division believes that at the time of the combined cycle test, the source had optimized operation of the turbine and that it is more that likely that if the simple cycle performance test was repeated for turbine No. 2, that the unit would meet the VOC emission limits at any load. Therefore there is no justification, nor is it allowable per EPA guidance, for exempting these units from the BACT emission limits. Therefore, in the operating permit, the VOC BACT emission limits will apply at all loads and at any temperature.

- 4) PM and PM₁₀ Use of pipeline quality natural gas.
- 5) For phased construction projects, the determination of BACT shall be reviewed and modified as appropriate for phases which commence construction more than 18 months after the initial granting of the permit (condition 2).

The Division requested information from Public Service indicating whether the second combustion turbine (turbine No. 3) had commenced construction within 18 months of the issuance of the construction permit. Public Service indicated that support infrastructure for turbine No. 3 had

commenced within 18 months of issuance of the construction permit. Therefore an additional BACT review was not required for turbine No. 3. Since this requirement has been met with the original BACT analysis it is not necessary to include this requirement in any form in the permit.

- b. The combustion turbines are subject to the requirements in 40 CFR Part 60, Subpart GG Standards of Performance for Stationary Gas Turbines (as adopted by reference in Colorado Regulation No. 6, Part A) which include the following specific requirements (condition 3):
 - NO_x emissions shall not exceed 137 ppmvd.
 - SO₂ emissions shall not exceed 0.015 percent by volume at 15 percent oxygen and on a dry basis.
 - Fuel consumption shall be continuously monitored

The above requirements were specifically identified in construction permit 94WE609 PSD, however there were some errors in these requirements. Specifically, the NO_x limitations are determined by calculation and it appears that the Division calculated the standard incorrectly. The correct NO_x limit should be 105.4 ppm, as identified in the source's original PSD permit application; however, this limitation will not be included in the operating permit for the reasons provided in the streamlining discussion below. In addition to the SO₂ emissions limit, these combustion turbines are also subject to a fuel restriction limitation. The limitation prohibits the burning of fuel that contains greater than 0.8 weight percent sulfur (40 CFR Part 60 Subpart GG § 60.333(b)). Finally, the construction permit identifies the fuel monitoring requirements incorrectly. NSPS Subpart GG requires the source to monitor sulfur and nitrogen content of the fuel on a daily basis (40 CFR Part 60 Subpart GG § 60.334(b)(2)). The fuel monitoring requirement will not be included in the operating permit for the reasons provided in the streamlining discussion below.

- c. The heat recovery steam generators (HSRG) are subject to the requirements in 40 CFR Part 60, Subpart Da Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978 (as adopted by reference in Colorado Regulation No. 6, Part A), when fuel is fired in the duct burners, which includes the following specific requirements (condition 3):
 - Particulate matter emissions shall not exceed 0.03 lbs/mmBtu
 - Opacity of emissions shall not exceed 20 percent opacity (6-minute average) except for one six-minute period, per hour, not to exceed 27 percent (40 CFR Part 60 Subpart Da § 60.42a(b)). Note that this requirement was not included in the original construction

permit.

Sulfur Dioxide emissions shall not exceed 0.20 lbs/mmBtu, on a 30-day rolling average (40 CFR Part 60 Subpart Da § 60.43a(b)(2) & (g)). Note that this requirement was not included in the original construction permit.

As this requirement is somewhat confusing, the Division has tried to clarify this requirement. 40 CFR Part 60 Subpart Da § 60.43a(b)(2) specifically states that the SO₂ limitation is "100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.2 lbs/mmBtu". Since these units burn natural gas, emissions will be below 0.2 lbs/mmBtu (40 CFR Part 75, Appendix D allows sources burning pipeline quality natural gas to use a default emission factor of 0.0006 lbs/mmBtu). Because emissions are below 0.2 lbs/mmBtu the source may emit 100% of the potential combustion concentration, i.e. no limits. However, since this "no SO₂ limits" only applies if emissions are below 0.2 lbs/mmBtu, the Division included the upper bound of 0.2 lbs/mmBtu as the emission limitation.

• Nitrogen oxide emissions are limited to 0.20 lbs/mmBtu, on a 30-day rolling average (40 CFR Part 60 Subpart Da § 60.44a(a)(1)). In addition, Subpart Da specifies a NO_x reduction limitation of 25% of the potential combustion concentration (40 CFR Part 60 Subpart Da § 60.44a(a)(2)). Note that the reduction requirement was not included in the original construction permit.

Note that the construction permit indicated that the NO_{χ} limitation of 0.20 lbs/mmBtu was not applicable as the BACT requirement was more stringent. However, there was no demonstration in the master file showing that the BACT requirement was more stringent. In their comments submitted during the Public Comment period (received October 21, 1999), the source provided a demonstration that the NSPS NO_{χ} limitation was less stringent that the BACT limit. Therefore, the NSPS NO_{χ} limitation was streamlined out of the operating permit. For reasons provided in the streamlining discussion below, the NO_{χ} reduction limit has not been included in the operating permit.

 A continuous monitoring system shall be installed, calibrated, maintained and operated for measuring NO_x emissions and either O₂ or CO₂ (40 CFR Part 60 Subpart Da § 60.47a(c) & (d)). This requirement was not specifically identified in the original construction permit. Additional requirements from 40 CFR Part 60 Subpart Da § 60.46a [compliance provisions], § 60.47a [emission monitoring], § 60.48a [compliance determination procedures and methods] and § 60.49a [reporting requirements].

Since the source has demonstrated that the NSPS Da NO_x limitation is less stringent than the BACT limitation, the NSPS requirements for compliance provisions, emission monitoring, compliance determination procedures and methods and reporting requirements do not apply, as the NSPS NO_x limitation will be streamlined out of the operating permit. The Division has not streamlined the NSPS Da SO₂ emission limits out of the permit, however, since natural gas is used as fuel, compliance with the SO₂ emission limit is monitored by burning only natural gas. NSPS Da does not require a continuous emission monitor for SO₂ for those units burning natural gas as fuel. Therefore, the Division does not consider that the NSPS requirements for compliance provisions, emission monitoring, compliance determination procedures and methods and reporting apply for the SO₂ requirements. Therefore, these requirements have not been included in the operating permit.

The above discussion indicates that no continuous emission monitor is required for SO_2 emissions and that the NSPS Da NO_X emission limits have been streamlined out of the permit and subsequently the requirements in 40 CFR Part 60 Subpart Da, §§ 60.46a thru 60.49a have been determined to not apply. Therefore, it follows that the requirement to install continuous emission monitors for NO_X would not apply. However, the Division specifically included certain requirements in construction permit 94WE609 PSD from the NSPS general provisions (excess emission reporting and notification of continuous monitoring system demonstrations (§ 60.7) and monitoring requirements (§ 60.13)) that indicate that the Division intended that the continuous emission monitoring systems for these units (as required by construction permit 94WE609 PSD, condition 9 - item h in this document) be subject to the NSPS requirements.

Although NSPS Subpart Da requirements only apply to the HRSG when the duct burners are burning natural gas, the Division is applying these requirements to the combustion turbine and the HRSG since there is no separate stack or CEM for the duct burners. Exhaust from the duct burners and the turbine exit the same stack. Note that only the SO₂ and PM limitations are included in the operating permit and compliance with these requirements are monitored by burning natural gas.

- d. This facility is subject to the requirements in 40 CFR Part 60, Subpart A General Provisions (as adopted by reference in Colorado Regulation No.
 6, Part A) which include the following specific requirements (condition 3):
 - Circumvention (40 CFR Part 60 Subpart A § 60.12)
 - Good operating practices (40 CFR Part 60 Subpart A § 60.11(d))

The construction permit specifically identified other requirements as NSPS general provisions, however, the Division will include some of these requirements elsewhere in the operating permit (i.e. under continuous monitoring system requirements and performance testing requirements) rather than as a "general provision". The construction permit identified the notification requirements for construction and initial startup (40 CFR Part 60 Subpart A § 60.7). However, since construction has been initiated and all phases have started up, this requirement will not be specifically identified in the construction permit. In addition, the construction permit specifically identified the general provision regarding demonstrating compliance with the opacity requirements (40 CFR Part 60 Subpart A § 60.11). However, the Division did not include this requirement since natural gas will be used as fuel to monitor compliance with the opacity requirements.

- e. These turbines are subject to the **State-only** requirements in Colorado Regulation No. 6, Part B as follows (condition 4):
 - Opacity of emissions shall not exceed 20% (Reg 6, Part B, Section II.C.3). Note that this requirement was not included in the original construction permit. Because Reg 6 Part B has incorporated 40 CFR Part 60 Subpart A (NSPS General Provisions), this opacity standard does not apply during startup, shutdown and malfunction in accordance with § 60.11(c).
 - SO₂ emissions shall not exceed 0.35 lbs/mmBtu

The SO₂ emission limit shall not be included in the operating permit for the reasons provided in the streamlining discussion below.

f. Emissions of air pollutants from **each** combined cycle combustion turbine (condition 6) as follows:

Pollutant	Short Term Limit	Annual Limit (tons/yr)
PM	9 lbs/hr	39.4
PM ₁₀	9 lbs/hr	39.4
SO ₂	1.4 lbs/hr	4.7

Pollutant	Short Term Limit	Annual Limit (tons/yr)
NO _x	3,263 lbs/day	496.1
	3,687 lbs/day*	560.6*
СО	860 lbs/hr (for ambient temperature > 0 ∘F)	465.4
	2,060 lbs/hr (for ambient temperature ≤ 0 ∘F)	
	750 lbs/hr* (for ambient temperature > 0 ∘F)	169.7*
	1,984 lbs/hr* (for ambient temperature ≤ 0 ∘F)	
VOC	352 lbs/day	21.4 tons/yr

^{*} This limit is no longer in effect and will not be included in the operating permit, since it expired upon start-up of combined cycle (Turbine No. 2 began combined cycle operation in March 1998)

Note that although this condition indicates "combined cycle" the Division intended these limits to apply to the combustion turbine/HRSG regardless of the mode of operation.

Note that the Division's short term emission limit policy (based on the April 16, 1998 Colorado AQCC directive) discussed in Section I of this document does not apply to these combustion turbines since they are subject to BACT requirements. However, the Division will remove the hourly limitation on SO_2 , since permitted SO_2 emissions are below the PSD significance levels and therefore a BACT analysis for SO_2 emissions was not required. In addition, the source did model the SO_2 impacts from this facility with their initial construction permit (PSD) application and the impacts were significantly below the required levels.

In Public Service's comments on the draft operating permit (submitted May 25, 1999), the source requested that the short term emission limits for CO, NO_X and VOC be removed from the permit. The Division's short term emission limit policy requires that short term emission limits remain in the permit if they represent BACT emission limits or are necessary to protect the NAAQs. The Division considers the ppm limits, not the short term (hourly or daily) limits to be BACT limits. Therefore, these short term limits may be removed from the permit if not needed to protect the

NAAQS. Since there is no NAAQS for VOC and since the NAAQS for NO_X is an annual average, the short term emission limits for these pollutants can be removed from the permit. The hourly PM emission limit was also removed from the permit for the same reason as the VOC short term limit, there are no NAAQS for this pollutant. The CO standards are in terms of a 1-hour and 8-hour average. The modeling performed for the original PSD permit (95WE609 PSD) was performed at the highest short term CO emission rate of 2,060 lbs/hr per turbine. At this rate, the modeling indicated that neither the 1-hour or 8-hour average would be exceeded. Therefore, these hourly limits have been removed from the permit, with the exception that during startup and shutdown, the hourly CO emission limit of 2,060 lbs/hr is retained. Only the PM_{10} short term emission limit will remain in the permit, as this limitation is necessary to protect the NAAQS for PM_{10} .

Compliance with annual emission limits listed above shall be monitored on a rolling twelve month total. On the first day of each month a new twelve month total is calculated using the previous twelve months data (condition 7).

The Division believes that the requirements to calculate emissions on the first day of the month is overly stringent and conflicts with our general operating permit protocol. The operating permit therefore, will be written to require emission calculations to be calculated by the end of the subsequent month.

g. The source shall be limited to the maximum natural gas consumption rates as follows (condition 8):

Combined cycle mode: 1.91 mmSCF/hr and 16,090 mmSCF/yr Simple cycle mode: 1.43 mmSCF/hr and 12,507 mmSCF/yr

Note that if a turbine is operated in both modes over a twelve month period, the consumption limits shall be prorated based on the hours of operation in each mode.

The requirement to prorate fuel consumption will not be included in the operating permit as the Division finds the prorating requirement to be a somewhat onerous recordkeeping requirement. Since the emissions of most pollutants are determined by the CEM, the Division will presume that if either combustion turbine was operated in both simple and combined cycle mode for any twelve month period, they are in compliance with the fuel consumption limitation if fuel consumption for that twelve month period meets the fuel consumption limitation for the combustion turbine when operating in combined cycle mode. The above discussion will be

reflected in the operating permit.

Although the Division has determined that short term emission limits must remain in the permit since this source is subject to PSD requirements (BACT), the Division will remove the short term emission limits for natural gas consumption for the following reasons. Protection of the NAAQS is based on the short term emission limit, not the short term fuel consumption limit. Since for all pollutants, except PM and PM₁₀, emissions are determined by a CEM the short term fuel consumption limits are not necessary to verify compliance with a short term emission limit. In the case of PM and PM₁₀, the emission factor is based on stack testing (in lbs/mmBtu). When the emission factor is multiplied by the hourly fuel consumption limits in the construction permit, PM and PM₁₀ emissions are much lower than the hourly emission limit.

- For each turbine a continuous emission monitor system (CEM) shall be installed, calibrated and operated on the exhaust stack to determine and record:
 - exhaust gas flow rate (parametric)
 - moisture content (parametric)
 - concentration of oxides of nitrogen
 - emissions of oxides of nitrogen
 - concentration of carbon monoxide
 - emissions of carbon monoxide
 - minimum combustion turbine load
 - average combustion turbine load
 - average hourly ambient temperature
 - flow rate of pipe line quality natural gas
 - operating condition (i.e. start-up, shutdown, normal)

Note that for reasons previously discussed, the requirements to monitor minimum turbine load, average hourly temperature and operating condition (i.e. startup, shutdown and normal).

As discussed in item k below, the exhaust gas flow and moisture content have not been included in the operating permit.

i. An accurate and verifiable correlation shall be developed between the emissions of NO_X and/or CO and VOC. This shall include all the anticipated conditions of operations. This correlation shall be submitted to and concurrence obtained from the Division. Emissions of VOC shall be calculated based on the correlation and prevailing conditions. These records shall be updated on a daily basis (condition 9).

The source has submitted (memo dated December 4, 1996) to the

Division, a correlation between VOC and load which was developed based on the stack testing performed for turbine No. 2. This information has been included in the data acquisition and handling system of the CEM for turbine No. 2. As of this time, the Division has not approved the correlation for turbine No. 2. The Division has requested additional information from the source in order to approve this correlation and the source submitted this information May 25, 1999. If, in the review and approval process for this correlation, the Division determines that modifications need to be made to the correlation and subsequently the data acquisition and handling system or that additional data, including any additional performance testing, is needed to approve the correlation, the source shall make the necessary changes and/or provide the additional data.

A correlation between VOC and turbine load will need to be developed for turbine No.3 and this data needs to be included in the data acquisition and handling system of the CEM for turbine No. 3. The source indicated in their comments received during the Public Comment period that source testing to develop the VOC correlation of turbine No. 3 was performed October 5 & 6, 1999 and that the test results and correlation will be submitted to the Division by the end of November 1999. The correlation for turbine No. 3 is also subject to Division review and approval as discussed for Turbine No. 2.

j. Sulfur dioxide emissions shall be tracked in the CEM data logging system and shall be calculated based upon the sulfur in the natural gas by weight and the natural gas flow. An automatic natural gas sampler shall be installed in the gas supply line that automatically samples each 40 mmSCF and shall be analyzed monthly (condition 9).

The existing CEM data logging system does track SO₂ emissions using natural gas flow. 40 CFR Part 75, Appendix D requires that an in-line fuel flow meter be installed and operational to monitor fuel flow to the combustion turbines for each hour fuel is combusted. 40 CFR Part 75, Appendix D allows SO₂ emissions to be based on fuel flow (heat input) and a default emission factor (0.0006 lbs/mmBtu) if burning pipeline natural gas. The Division understands that currently, PSCo is using the default emission factor to determine SO₂ emissions for the purposes of APEN reporting and Acid Rain reporting but are automatically sampling gas, analyzing it monthly and using the analytical results to monitor compliance with SO₂ limitations identified in the construction permit. Public Service has indicated that in the future they will use the default emission factor for all compliance monitoring and therefore the Division will not include the requirement to sample each 40 mmSCF of natural gas in the operating permit. However, as required by 40 CFR Part 75,

Appendix D, 2.3.1.4, in order to use the default emission factor, the source must demonstrate using any of the methods in 2.3.1.4.(a) that the fuel has a hydrogen sulfide content of less than 0.3.

k. Exhaust gas flow rate and moisture content of exhaust gas may be parametrically monitored. Procedure and accuracy shall conform to the relative accuracy requirements (condition 9).

The source has indicated that they do not have a exhaust gas flow monitor but that exhaust gas flow rate and moisture content are based on fuel flow to the system. Exhaust gas flow and moisture content are calculated and recorded in the data acquisition and handling system. In their comments submitted during the Public Comment period, the source indicated that since these parameters are not necessary to monitor compliance with any applicable requirements that they should not be required to monitor these parameters. The monitors are measuring and reporting dry emissions. Since the source is monitoring SO₂ emissions in accordance with the procedures in 40 CFR Part 75 Appendix D, no flow monitors are required. Therefore the requirement to parametrically monitor there requirements is not included in the operating permit.

I. Quality-assured data from the CEM shall be available for at least 90% of the duration of operation of the turbine. For periods when such quality-assured data is not available, but the operation is normal, the highest reading recorded for a similar operating condition used during the previous 30 day period shall be used for determining the emissions. Similar operating condition is defined as the point that has the maximum one-hour NO_x emission rate during the previous 30-day period for the appropriate load range of the turbine regardless of the ambient temperature. A total of ten load ranges, at intervals of 10% of total combustion turbine load, shall be used. In case of non-availability of quality assured data in the appropriate load range, the next lower load range shall be used. CEM data shall be reported to the Division on a calendar quarterly basis. Such reports shall include all exceedances of the concentration and emission limits (condition 9).

In their response to comments on the draft permit (submitted May 25, 1999), the source indicated that they were unable to replace data in the manner specified in the construction permit. The Division and the source agreed that data would be replaced using the procedures in 40 CFR Part 75 for SO_2 , NO_X and CO. The CO replacement procedures would be the same as the replacement procedures in Part 75 for NO_X . The source indicated that significant changes would have to be made to the CEM for the CO replacement procedures, however, they would do manual calculations to replace CO data until the CEM was modified. The Division

will allow the source one year from the date of permit issuance to replace data by hand, after this time, the Division expects that all data replacement can be made by the CEM.

In their second set of comments (received September 16, 1999) the source requested that the requirement to obtain quality assured data 90% of the time be removed from the permit. The source indicated that this issue of monitor availability is subject to the Division's enforcement discretion and should not be included in the permit. The Division's operating permit unit agrees with this and therefore is removing this requirement from the permit. It should be noted that in accordance with 40 CFR Part 75 and Part 60 the continuous emission monitors shall be operating at all times with certain exceptions. The 90% data availability requirement is generally less stringent that the Part 75 and 60 requirements.

- m. The load at which the turbine is operating shall be continuously measured and recorded. Records of turbine load and operation rates shall be made available to the Division for inspection upon request (condition 10).
- n. Visible emissions shall not exceed 20% (condition 12)
- o. At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution prevention and control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (condition 15).

This condition (good operating practices) will be included with the other NSPS general provisions as discussed in item d above.

p. The concentration limits and short term emission limits shall not be in effect for one hour after start-up or initiation of shutdown of a combustion turbine in simple cycle mode, or for four hours after startup or initiation of shutdown of a combustion turbine in combined cycle mode. When the combustion turbine is operating in simple cycle mode and a heat recovery steam generator (HRSG) start-up is initiated, or the HRSG is shutdown, no short term emission limits shall be in effect for two hours. The emissions during both the start-up and shutdown modes shall be monitored, recorded and summed to be included in determining compliance with annual emission limitations (condition 15).

The source requested in their original PSD application relief from the concentration limits and short term emission limits (essentially the BACT limits) during periods of startup and shutdown. Although the Division granted the source's request, we did so in error. EPA guidance (John B. Rasnic to Linda M. Murphy, dated January 28, 1993, "Automatic or Blanket Exemptions for Excess Emissions during Startup and Shutdowns Under PSD") states that "... PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown....the exemptions granted under some New Source Performance Standards (NSPS) are not applicable to this issue under PSD. The NSPS are technology based standards that are not directly required for meeting ambient standards." Furthermore EPA guidance (Kathleen M. Bennett to Regional Administrators, dated February 15, 1983, "Policy on Excess Emissions During Startups, Shutdowns, Maintenance and Malfunction") indicate that "...startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." In addition, futher EPA guidance (Kathleen M. Bennett to Regional Administrators, dated September 29, 1982, "Policy on Excess Emissions During Startup, Shutdown, Maintenance and Malfunction") states that "[i]n 1978, EPA adopted an excess emissions policy....this policy disallowed automatic exemptions by defining all periods of excess emissions as violations of the applicable standards. States can, of course, consider any demonstration by the source that the excess emissions were due to an unavoidable occurrence in determining whether any enforcement action is required." Therefore, the Division interprets that BACT limits apply during all modes of operation.

The BACT guidance documents (specifically, John B. Rasnic to Linda M. Murphy, January 28, 1993, "Automatic or Blanket Exemptions for Excess Emissions during Startup and Shutdowns Under PSD") address using alternate limitations during startup and shutdown and although they do not necessarily approve this method, they point out that these types of standards need to have clear definitions and limits and that the standard, should demonstrate compliance with the short term increments and standards, as well as the long term standards. As discussed in the June 15, 1999 meeting, the source and Division have agreed to use this approach to address the BACT startup and shutdown issues. At a maximum, the CO BACT limitation for startup and shutdown, is equal to the lbs/hr limitation that the source modeled in their initial PSD permit application (94WE609 PSD), which demonstrated compliance with both the 1-hr and 8-hr average standards. There are no PSD increments for

- CO. The NO_x standards are an annual standard and in the initial PSD permit (94WE609 PSD) application the modeling demonstrated that at an annual emission limit of 560.6 lbs/yr the NO_x standards and increments were not exceeded. Since the operating permit will still include an annual NO_x emission limit, the NAAQS will still be protected for the longer averaging time of one year for NO_x. Specifically, the annual NO_x limit to be included in the operating permit is 496.1 tons/yr, the 560.6 lbs/yr NO_x limit, which represented the worst case modeling was applicable prior to startup of the turbine in combined cycle mode. Therefore, the Division believes these alternate limits demonstrate compliance with the NAAQS and the permit will specifically identify the startup and shutdown conditions for which these BACT startup/shutdown limits apply. The permit will not limit these units to a number of hours for startups and shutdowns, as the number of these occurrences can vary depending on the demand for power. Minimizing startups and shutdowns is in the best interests of the source as frequent startups and shutdowns are hard on the turbines and can be costly since power cannot be generated during these periods.
- q. Source compliance tests shall be conducted on each turbine to measure emission rate(s) at various operating and load conditions for the pollutants identified below using EPA approved methods. The test protocol must be in accordance with the requirements of the APCD Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No source compliance test shall be conducted without prior approval from the Division (condition 17).

Particulate Matter (all PM₁₀) Oxides of Nitrogen Carbon Monoxide Volatile Organic Compounds Fomaldehyde

The initial compliance testing has already been completed on turbine No. 2. In their comments submitted during the Public Comment Period, the source indicated that initial compliance tests have been performed on turbine No. 3. The turbine was tested in simple cycle mode on March 15-19, 1999 and the report submitted April 19, 1999. The tests for combined cycle mode, with fuel fired to duct burner, were conducted October 5 & 6, 1999 and the report shall be submitted to the Division by the end of November 1999. Since the initial compliance tests have been completed, the Division will not include this requirement in the operating permit. However, since the initial performance tests for turbine No. 3 have not been approved, the Division may request further testing in order to approve the initial compliance testing. If necessary, the permit may be reopened as a result of the Division's review of these initial performance

tests.

Typically the Division does not require sources to conduct performance tests for both filterable and condensible particulate matter, primarily because many of the particulate standards (i.e. Reg 1 and NSPS) specify that the standard is based on filterable particulate matter. The Division determined that it was necessary to conduct performance tests to determine condensible particulate matter emissions on these combustion turbines for the following reasons. First of all, the source requested emissions of particulate matter based on manufacturers' guarantees which are much lower than AP-42 emission factors. The manufacturers' guarantee is based on filterable, noncondensible particulate matter emissions. AP-42 emission factors predict that condensible particulate matter emissions are more than two times higher than filterable particulate matter emissions. As required for a PSD permit, the source performed modeling to demonstrate no significant impact to Air Quality Related Values (AQRVs) or to the National Ambient Air Quality Standards (NAAQS). The source modeled PM₁₀ emissions at their requested levels which is the manufacturers' guarantee for filterable, noncondensible particulate matter emissions. In general the PM₁₀ modeling showed no significant impacts, however, there was one case (receptor grid type = 100 m spacing) which indicated that the Class II significance level for the 24-hour average was exceeded (5 μ g/m³ vs 5 μ g/m³), however, the PSD increment was not exceeded (28.31 μ g/m³ vs 30 μ g/m³). Since the PSD increment was not exceeded by a very small margin (1.7 μ g/m³) and not all particulate matter emissions were modeled (i.e. condensibles not included), the Division believes that the source must demonstrate that all particulate matter (filterable and condensible) emitted from each turbine is within the 9 lbs/hr limitation.

The Division will not require the source to conduct the performance test on formaldehyde. Formaldehyde is both a VOC and a hazardous air pollutant (HAP). The Division does not have the authority to regulate HAPs unless a source requests a synthetic minor permit to limit HAP emissions. Since the Division is requiring the performance test for VOC, which will capture the formaldehyde emissions, the Division does not believe it is necessary or allowable to require the performance test for formaldehyde. In addition, it should be noted that the performance test for turbine No. 2, indicated that the emissions of formaldehyde are much less than the source anticipated in their construction permit (PSD) application. Emissions of formaldehyde, based on the stack test, range from 0.5 tpy (simple cycle mode) to 1.5 tpy (combined cycle mode with fuel fired in the duct burners).

r. This source is subject to the Common Provisions Regulation Part II,

Subpart E, Upset Conditions and Breakdowns (condition 19).

The Division is preliminarily proposing to include the language in the Common Provisions concerning upsets in the General Conditions, Section V, of the permit, under item 4. Prior to issuance of the final permit, the Division will make a final decision as to whether this condition will be included in the operating permit.

- s. An annual report shall be submitted to the Division by April 30, in respect of the previous year. The report shall at the minimum include (condition 20):
 - Consumption of Natural Gas
 - Operating loads, and hours of operation at each operating condition
 - Total emissions of all pollutants as determined by the CEM
 - Emissions of VOC as calculated using the correlations
 - Episodes of emission exceedances
 - Certification of Compliance/Non-compliance of permit conditions
 - Status of further development of Dry Low NO_x combustion technology
 - Upset conditions and remedial measures
 - Modifications/measures for further pollution prevention

Since most of the information required by this annual report is submitted to the Division via APENs, excess emission reports or the Title V semi-annual monitoring reports and annual compliance certifications, the Division will not include this report as an applicable requirement in the operating permit.

t. This source is subject to the odor requirements of Regulation No. 2 (condition 21).

This condition is included in the General Conditions of the operating permit. Based on engineering judgement, the Division does not believe that the combustion turbines are a significant source of odorous emissions, so this requirement will not be included as a specific condition for these units and will not have specific periodic monitoring requirements. However, the source is still subject to the requirements of Regulation No. 2 as a **state-only** general condition.

Although not specifically identified in Colorado Construction Permit 94WE609 PSD, the source is also subject to the following applicable requirements:

A. Colorado Regulation No. 1

- Opacity shall not exceed 20% during normal operations (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate matter emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)
- Sulfur dioxide emissions shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)

B. Acid Rain Requirements

- Allocated SO₂ allowances are listed in 40 CFR 73.10(b), however, since these are new units, no allowances were allocated. SO₂ allowances must be obtained per 40 CFR Part 73 to cover SO₂ emissions for the particular calendar year.
- There are no NO_x emission limitations since these units are not coal-fired boilers.
- Acid rain permitting requirements per 40 CFR Part 72.
- Continuous emission monitoring requirements per 40 CFR Part 75.
- This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

Opacity

When the turbines are operated in simple cycle mode or in combined cycle mode without fuel fired in the duct burners, there are three separate opacity requirements. The Regulation No. 1, normal conditions (20%), the Regulation No. 1 special conditions (30%) and the state-only Regulation No. 6, Part B (20%). The Regulation No. 6 requirement applies at all times except during startup, shutdown and malfunction. The Reg 1 20% standard applies, except during those special conditions where the Reg 1 30% standard applies. Those special conditions are: fire building, cleaning of fire boxes, soot blowing, startup, process modification or adjustment or occasional cleaning of control equipment. The state-only Reg 6 opacity requirements are more stringent than the Reg 1 requirements under all Reg 1 special conditions except startup. The Reg 1 (20% normal/30% special) opacity requirements are more stringent during startup, shutdown and malfunction. Since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the

operating permit.

When the turbines are operating in combined cycle mode with fuel being fired in the duct burners, the turbines are subject to the opacity requirements mentioned above and are also subject to the NSPS opacity requirements. The NSPS opacity requirements are not applicable during periods of startup, shutdown and malfunction. The NSPS opacity requirements are more stringent that the Reg 1 requirements under all Reg 1 special conditions except startup but are less stringent that the state-only Reg 6 requirements. The Reg 1 (20% normal/30% special) opacity requirements are more stringent during startup, shutdown and malfunction. Again, since no one opacity requirement is more stringent than the others at all times, all four opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency.

It should be noted that since these turbines burn pipeline natural gas as fuel, the Division will presume, in the absence of evidence to the contrary, that these unit are in compliance with all of the opacity requirements.

NO_X

Since the NSPS Subpart GG and BACT concentration limits are in the same units they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. Although, not specifically stated in NSPS Subpart GG, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the quarterly excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "..it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, even with the secondary BACT limit for startup and shutdown, the NSPS Subpart GG limits will be streamlined out of the operating permit.

When these units are operating in combined cycle mode with fuel being fired in the duct burners, the duct burners are subject to NSPS Subpart Da, which has a NO_{χ} emission limit and a NO_{χ} percent reduction limit. NSPS Subpart Da § 60.46a(b) specifically states that compliance with the NSPS Subpart Da NO_{χ} emission limit ensures compliance with the NSPS Subpart Da NO_{χ} percent reduction limit. Therefore, the NSPS Subpart Da NO_{χ} percent reduction limit will be streamlined out of the operating permit.

The NSPS Da NO_x requirement and the BACT NO_x requirement are in different units (lbs/mmBtu vs ppmvd corrected at 15% O₂) and have different averaging times (rolling 30-day vs hourly). Although the construction permit (94WE609 PSD) indicated that the NSPS Da NO_x limit was not applicable as the BACT limit was more stringent, there was no demonstration of this in the master file. Therefore, the Division did not initially consider streamlining the NSPS Da NO_x limit. However, in their comments submitted during the Public Comment period (received October 21, 1999), the source provided a demonstration that the NSPS Da standard was less stringent than the BACT standard. This demonstration was based on the conversion procedures in 40 CFR Part 75 Appendix F (used to convert measured data from a CEM into units of the standard) and showed that at 17 ppm (BACT limit during normal operations) NO_x emissions in lbs/mmBtu are well below the standard on an hourly average. Note that the NSPS Da NO_x standard does not apply during startup and shutdown but the BACT limit does. Therefore, the Division has streamlined the NSPS Da NO_x limit out of the permit in favor of the more stringent BACT requirement.

<u>SO</u>₂

Only the Regulation No. 1, Regulation No. 6, Part B and NSPS Subpart Da (which only applies when the combustion turbines operate in combined cycle mode with fuel being fired in the duct burners) SO₂ requirements are in the same units and can therefore be compared for the purposes of streamlining.

The Regulation No. 1 and No. 6, Part B SO_2 standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement and since Regulation No. 6, Part B incorporates the NSPS General Provisions (40 CFR Part 60 Subpart A), the SO_2 requirements do not apply during startup, shutdown and malfunction (as discussed in the NO_X streamlining section above). Therefore, the Regulation No. 1 SO_2 requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The NSPS Subpart Da requirement of 0.2 lbs/mmBtu appears to be more stringent than the Regulation No. 1 requirement. However, the NSPS Subpart Da requirement of 0.2 lbs/mmBtu is not applicable during periods of startup, shutdown and emergency condition as indicated in § 60.46a(c) and the Regulation No. 1 requirements apply all the time. Therefore, during certain periods (startup and shutdown) the Regulation No. 1 requirement is more

stringent and as a result neither of these requirements can be streamlined out of the permit.

PM

Although the NSPS Subpart Da particulate matter requirements (0.03 lbs/mmBtu), which apply only when the combustion turbines are operating in combined cycle mode with fuel being fired in the duct burners, appear to be more stringent than the Regulation No. 1 requirements, neither can be streamlined out of the operating permit for the following reason: the NSPS Subpart Da requirements do not apply during periods of startup, shutdown and malfunction, as specifically mentioned in § 60.46a(c), but the Regulation No. 1 particulate matter limits apply at all times. Therefore, during certain periods (i.e. startup, shutdown and malfunction), the Regulation No. 1 particulate matter limit is more stringent and as a result neither requirement can be streamlined out of the permit.

Monitoring

This source is subject to several monitoring requirements. Continuous emission monitors (CEMs) are required by Acid Rain (40 CFR Part 75) and by the construction permit (94WE609 PSD) issued by the Division. The CEMs required by the construction permit are subject to QA/QC and reporting requirements in the NSPS general provisions. The source requested in their September 16, 1999 comments on the draft permit that they be allowed to use the quality assurance/quality control procedures of Part 75 for their monitors, rather than the Part 60 requirements. In the past, the EPA has indicated that Part 75 monitors may be used to monitor NSPS requirements and that the continuous emission monitoring requirements in Part 75 are equivalent to or more stringent than the NSPS requirements. The EPA has indicated that they will accept Acid Rain CEMs as NSPS CEMs provided the source demonstrates compliance with all NSPS requirements (see attached). Note that the Division has streamlined out the NSPS Da NO_x requirements and is requiring the source to use natural gas as fuel to monitor compliance with the NSPS Da SO₂ requirements. Therefore, the NSPS CEM requirements, with the exception of the excess emission reporting requirements (40 CFR Part 60 Subpart A § 60.7(c) & (d)) will be streamlined out of the permit in favor of the Part 75 requirements.

NSPS Subpart GG requires daily sampling of fuel to determine the nitrogen and sulfur content of the fuel. In an August 14, 1987 memo, the EPA waived the fuel sampling requirements to determine the nitrogen content for pipeline quality natural gas. The Acid Rain requirements allow sources that burn natural gas to use an alternate monitoring method in lieu of a continuous emission monitor for SO₂. These requirements are in 40 CFR Part 75, Appendix D. Specifically, this monitoring method requires the source to monitor fuel fed to the combustion

turbine for every hour that it combusts fuel. The source may then either sample and analyze natural gas for sulfur content or they may use the default SO_2 emission factor to determine SO_2 emissions. The default emission factor may be used if pipeline natural gas is burned. In order to use the default emission factor, the source must demonstrate using any of the methods in 40 CFR Part 75, Appendix D, Section 2.3.1.4.(a) that the fuel has a hydrogen sulfide content of less than 0.3 grain/100 scf. The source is using the default emission factor provided by Part 75 Appendix D for the purposes of determining SO_2 emissions. Therefore, the NSPS Subpart GG requirement to sample fuel daily for sulfur content will be streamlined out of the permit in favor of the Part 75 pipeline quality natural gas requirement.

2. Emission Factors - In general, the source will be monitoring compliance with the emission limitations using their continuous emission monitor. However, emissions of PM and PM_{10} will be determined using heat input to the combustion turbine/HRSG and an emission factor. The source proposed to use emission factors from the stack test performed on turbine No. 2. The emission factors are as follows:

<u>Pollutant</u>	Emission Factor	Mode/Stack Test Date
PM PM ₁₀	0.005 lbs/mmBtu 0.005 lbs/mmBtu	Simple/Combined (no fuel in duct burners), 8/12-14/97 Simple/Combined (no fuel in duct burners), 8/12-14/97

Note that the stack test results for turbine No. 2, when operating in combined cycle mode with fuel fired in the duct burners predicted a lower PM/PM_{10} emission factor. The Division is using the most conservation emission factor in the operating permit.

VOC emissions are recorded on the data acquisition and handling system ("DAHS") for the combustion turbine CEMs, however, VOC emissions are not directly measured. The source has submitted (memo dated December 4, 1996) to the Division, a correlation between VOC and load which was developed based on the stack testing performed for turbine No. 2. This information has been included in the DAHS of the CEM for turbine No. 2. As previously indicated, the Division is currently reviewing this correlation and changes to the correlation may be required based on the Division's review. A correlation between VOC and load will need to be developed for turbine No. 3 and this data needs to be included in the DAHS of the CEM for turbine No. 3.

Although SO_2 emissions are recorded on the DAHS, they are not directly measured by the CEM. The source has an in-line fuel flow meter that records fuel fed to the combustion turbine for every hour the combustion turbine burns fuel. This data is recorded in the DAHS and SO_2 emissions are calculated based on heat input (mmBtu/hr) as determined by the DAHS and a default emission factor for SO_2 that is specified in 40 CFR Part 75, Appendix D.

- 3. Monitoring Plan Conditions 1.1 through 1.16 (simple cycle and combined cycle operation, with no fuel fired in the duct burners) and 2.1 through 2.7 (combined cycle operation, with fuel fired in the duct burners) identify the compliance demonstration and monitoring requirements for these turbines. Monitoring requirements are similar in all operating modes, however, combined cycle operation with fuel being fired in the duct burners has some additional requirements. For all pollutants except PM and PM₁₀, compliance with the emission limitations shall be monitored using the continuous emission monitors. Compliance with the fuel consumption limits shall be monitored using the in-line fuel flow meters which record on the DAHS of the continuous emission monitors. Compliance with all annual emissions shall be monitored using a twelve month rolling total of emissions. Compliance with the PM and PM₁₀ emission limits (PM₁₀ hourly and annual and PM annual) shall be monitored using fuel consumption and emission factors based on stack testing. Compliance with the opacity limits, the PM (reg 1 and NSPS) limitations and the SO₂ emission limitations (except for hourly and annual limits) shall be monitored by using natural gas as fuel. In addition, within the last 18 months of the permit term, the source shall conduct a performance test for PM (all PM₁₀) on both combustion turbines to monitor compliance with the hourly PM limitations.
- **4. Compliance Status -** The source certified that they were in compliance with all applicable requirements. At the time this permit application was submitted only one combustion turbine was installed and operational (simple cycle only).
- B. Unit B001: External Combustion Boiler, Babcock and Wilcox Model No. FM-1656, Serial No. NB22845, Rated at 70 mmBtu/hr, Natural Gas Fired.
 - 1. Applicable Requirements This boiler was first placed into service in 1969. The boiler was modified to burn natural gas only in September 1997. The modification from burning natural gas only as opposed to No. 2 fuel oil only results in overall emission increases (based on PTE) of CO (~ 13 tpy) and VOC (~1 tpy) and therefore a construction permit is required for this modification if the source chooses to operate this unit above APEN de minimis levels. Although the source did not exceed APEN de minimis levels in 1998, they would like the flexibility to operate this unit above de minimis levels and therefore have requested a construction permit for this unit. The Division is using the procedures set forth in Colorado Regulation No. 3, Part C, Section II.B.7 to process a construction permit concurrently with this operating permit. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after this unit commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self certification that this unit can comply with the applicable requirements.

Although the modification to this unit (the conversion from fuel oil burning to natural gas burning) triggered the requirement to obtain a construction permit, it is not considered a modification for the purposes of New Source Performance Standards, either federal (40 CFR Part 60 (as adopted in Colorado Regulation No. 6, Part A)) or state (Colorado Regulation No. 6, Part B), since there was not an emissions increase for those pollutants for which there is a standard in the applicable NSPS (Subpart Dc).

The following applicable requirements have been identified for this unit:

- a. Opacity shall not exceed 20% during normal operations (Reg 1, Section II.A.1)
- b. Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4).
- c. Particulate matter emissions shall not exceed the following (Reg 1, Section II.A.1.b):

 $PE = 0.5 (FI)^{-0.26}$

Where: PE = particulate emissions (lbs/mmBtu)

FI = fuel input (mmBtu/hr)

At the maximum fuel input rate as specified in the permit application (70 mmBtu/hr), this requirement is calculated as 0.166 lbs/mmBtu. The numerical value will be included in the permit rather than the equation.

- fuel consumption is limited to the following:
 Natural gas consumption shall not exceed 651.7 mmSCF/yr
- e. Emissions of air pollutants shall not exceed the following:

PM	0.6 tons/yr
PM ₁₀	0.6 tons/yr
SO ₂	0.2 tons/yr
NO_X	32.6 tons/yr
CO	27.4 tons/yr
VOC	1.8 tons/yr

Note that these emissions are based on the APEN submitted to the Division on April 23, 1999 and the corrected fuel consumption as indicated in their May 25, 1999 comments. Since the potential to emit of PM, PM_{10} , VOC and SO_2 are below APEN de minimis levels and there is a limit on natural gas consumption these emission limits will not be included in the operating permit.

Although the NO_{χ} emission limits for this auxiliary boiler are above the de minimis levels for modeling (20 tpy), the Division did not believe it was necessary to perform a screen model on this emission unit. For the original PSD permit (94WE609 PSD), the source modeled NO_{χ} emissions from the turbines at 560.6 tpy per turbine and the modeling demonstrated that the NAAQS were not violated nor were the increments exceeded at the 560.6 tpy per turbine emission level. The NO_{χ} limits in the operating permit are 496.1 tpy per turbine, much less than the modeled emission rate. Therefore, the increase in NO_{χ} emissions from running the auxiliary boiler above APEN de minimis levels was already covered in the modeling performed for the original PSD permit.

2. Emission Factors - Emissions from this unit are from the combustion of natural gas. The pollutants of concern are Particulate Matter (PM and PM $_{10}$), Nitrogen Oxides (NO $_{\rm X}$), Sulfur Dioxide (SO $_{\rm 2}$), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC). Negligible quantities of hazardous air pollutants (HAPs) are produced through the combustion of natural gas. Approval of emission factors for this unit is necessary to monitor compliance with the emission limits. The source proposed in their application to use emission factors from EPA's Compilation of Air Pollutant Emission Factors (AP-42). The following emission factors are from AP-42, dated March 1998, Section 1.4, Tables 1.4-1 and 1.4-2, for small industrial boilers (10-100 mmBtu/hr).

<u>Pollutant</u>	Emission Factor
PM	1.9 lbs/mmSCF
PM ₁₀	1.9 lbs/mmSCF
SO ₂	0.6 lbs/mmSCF
NOx	100 lbs/mmSCF
CO	84 lbs/mmSCF
VOC	5.5 lbs/mmSCF

- **3. Monitoring Plan -** Conditions 3.1 through 3.5 identify the compliance demonstration and monitoring requirements for this unit. Monitoring requirements consist of monitoring and recording monthly fuel use and calculating emissions monthly. Use of natural gas as fuel shall be used to monitor compliance with the opacity and Reg 1 particulate matter requirements.
- **4. Compliance Status -** The source indicated in their Title V permit application that this unit was in compliance with all applicable requirements. The boiler was modified in September 1997 to burn natural gas only rather than fuel oil only. Based on PTE this modification triggered the permitting requirements in Reg 3, Part B. Although the source did not exceed APEN de minimis levels in 1997, they were exceeded in 1998. For this reason, the source requested a

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- C. Unit M001: One (1) Marley Cooling Water Tower, Model No. Cross-Flow DF-664, Design Rate of 156,00 gpm and One (1) Marley Service Water Tower, Model No. 6-48-3-02, Design Rate of 15,000 gpm
 - 1. Applicable Requirements Both the cooling water tower and the service water tower were first placed into service in 1976. A new APEN and an application for a construction permit were submitted with the Title V permit application. Construction Permit 97WE0189 was subsequently issued (initial approval, October 1, 1997). Public Service Company submitted a self-certification of compliance, signed by the Responsible Official, on the initial approval construction permit. A final approval construction permit was not issued but the appropriate provisions of the construction permit have been incorporated into the operating permit. The applicable requirements are as follows:
 - a. Visible emissions shall not exceed 20% opacity (condition 1).

This requirement will not be incorporated into the operating permit since cooling water and service water towers are not sources of opacity emissions by nature of their operations.

b. This source is subject to the odor requirements of Regulation No. 2 (condition 3).

This condition is included in the General Conditions of the operating permit. Based on engineering judgement, the Division does not believe that the cooling/service water towers are a significant source of odorous emissions, so this requirement will not be included as a specific condition for these units and will not have specific periodic monitoring requirements. However, the source is still subject to the requirements of Regulation No. 2 as a **state-only** general condition.

The process rate for both units is limited as follows (condition 6):
 Total water circulated shall not exceed:
 9.99 mmgal/hr* and 87,520 mmgal/yr

In their response to comments on the draft operating permit, the source indicated that they would be adding two cells to the service water tower and that in the future they would be modifying the service water pumps to increase the design rate to 15,000 gpm. For this increase an increase in annual limitation of total water circulated to 89,878 mmgal/yr is necessary. This increased annual limit of total water circulated will be included in the operating. Note that Public Service indicated that no increase in

emissions would be necessary for this modification.

d. Representative samples of recirculating water shall be analyzed at least once in any thirty (30) day period for total solids. Records of such analyses shall be maintained on site and made available to the Division for inspection upon request (condition 7).

Since the source has indicated that the total solids concentration of the recirculating water stays relatively consistent from month to month and since that concentration (200-400 ppm) is significantly less than the limitation (12,700 ppm), the Division will only require that the total solids concentration be verified semi-annually.

e. Emissions of air pollutants from the two (2) cooling/service water towers shall not exceed the following:

Particulate Matter (PM) 3.4 lbs/hr* and 14.9 tons/yr Particulate Matter < 10μ m (PM $_{10}$) 3.4 lbs/hr* and 14.9 tons/yr Volatile Organic Compounds (VOC)** 2.3 tons/yr

In the source's self-certification submittal for construction permit 97WE0189, the source requested the final approval construction permit be written in the format of another cooling water tower permit at another Public Service facility. That permit did not include the monthly recirculation water sampling, however, it did include additional operational parameters as follows:

Total solids concentration not to exceed 13,000 ppm Chlorination rate shall not exceed 1,825 hours/yr

Requirements for sampling and analyzing the recirculating water will still be included in the operating permit to determine the total solids concentration.

In order to accommodate the future modifications to the service water tower, without increasing the emission limits, the source has indicated, in their May 25, 1999 comments, that they would meet a lower total solids concentration limitation. The lower limitation of 12,700 ppm has been included in the operating permit. During the Public Comment period (comments received October 21, 1999), the source requested that the total solids concentration be removed from

^{*} The short term water circulation and emission limits have not been included in the operating permit as a result of the Division's short term emission limit policy (based on the April 16, 1998 Colorado AQCC directive).

^{**} The VOC emissions identified are chloroform emissions, the Division had previously identified chloroform in the construction permit as a HAP, which it is. However, chloroform is also a VOC.

the permit. The source indicated that the intent of the total solids limit in construction permits was to provide design levels to set an emission limit and to set maximum parameters that determine emissions. The intent was for the source to demonstrate that they were below maximum parameters and therefore demonstrate compliance with emission limits, without performing calculations. However, since the operating permit requires monthly emission calculations, there is no need to set a limit on the total solids concentration. Therefore, the total solids concentration limit has not been included in the operating permit.

Since the chlorination rate is used to determine emissions of chlorine (a HAP) from the towers it will not be included in the permit as a limitation since the Division does not have the authority to limit HAP emissions unless a source is requesting a synthetic minor limitation. In addition, although the source is required to report emission of HAPs for the purposes of APEN reporting and payment of fees, the Division has not as a policy included these calculations in the specific portions of the operating permit. The APEN reporting requirements and the requirement to pay annual fees are included in the General Conditions of the operating permit and the source is still subject to these requirements.

2. Emissions Factors - Since cooling towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as "drift" droplets. Particulate matter contained in the "drift" is considered an emission as well as any chlorine or chloroform from water treatment chemicals used in the cooling tower. Approval of emission factors for these units are necessary to verify compliance with the emission limits. The source proposed to calculate emissions from the cooling towers in the following manner:

 $PM = PM_{10} = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (31.3% <math>PM/PM_{10}$ from drift) x (Total solids concentration, ppm)

Where: % drift = 0.001%
31.3% PM from drift - from EPA-600/7-79-251a, November 1979,
"Effects of Pathogenic and Toxic Materials Transported Via Cooling
Device Drift - Volume 1, Technical Report", page 63

 $VOC = CHCl_3 = (water flow, gpm) \times (0.0527 lbs CHCl_3/mmgal)$

Where: 0.0527 lbs/mmgal emission factor - from letter from Wayne C. Micheletti to Ed Lasnic, dated November 11, 1992 (see attached)

3. Monitoring Plan - Conditions 4.1 through 4.4 identify the compliance demonstration and monitoring requirements for these units. Monitoring requirements consist of recording monthly water circulated and calculating emissions monthly. In addition, samples of circulating water shall be gathered and analyzed at least semi-annually to determine the total solids concentration.

4. Compliance Status - An APEN and an application for a construction permit were submitted with the Title V permit application. Construction permit 97WE0189 was subsequently issued. The cooling/service water towers are currently in compliance with all applicable requirements.

D. Unit F001: Fugitive Particulate Emissions from Vehicle Travel on Paved/Unpaved Roads

Roads to serve this facility were first placed in service in 1971. Fugitive particulate emissions are generated from vehicle traffic on paved and unpaved roads. The source identified fugitive emissions from this source as a significant emission source. This source of fugitive particulate emissions is subject to the fugitive particulate matter requirements under Reg 1, Section III.D.1.a. Since these roads are not haul roads, emissions from travel on these roads is not subject to APEN reporting requirements per Regulation No. 3, Part A, Section II.D.1.o. Emissions from these roads are also considered an insignificant activity per Regulation No. 3, Part C, Section II.E.3.o. Although these emissions are subject to the fugitive emission control requirements in Reg 1, this emission source will not be included in the Title V permit as a specific emission unit, since the Reg 1 fugitive emission control requirements are included in the General Conditions. Fugitive emissions from travel on roads will be included as an insignificant activity in Appendix A of the permit.

IV. Insignificant Activities:

General categories of insignificant activities include: in-house experimental and laboratory equipment, gas fired fuel burning equipment (< 5 mmBtu/hr), chemical storage tanks or containers (< 500 gal), landscaping and site housekeeping devices (< 10 HP), chemical storage areas (< 5,000 gal), storage of butane, propane and LPG (< 60,000 gal), venting of compressed natural gas, butane or propane gas cylinders (capacity < 1 gal), lube oil storage tanks (< 40,000 gal), fuel dispensing equipment, storage tanks with limited contents (< 400,000 gal), fuel burning equipment, for heating (< 10 mmBtu/hr), internal combustion engines (limited size or hours) and APEN de minimis emission sources.

Specific insignificant activities identified in the Operating Permit application are as follows:

<u>Units with emissions less than APEN de minimis - critieria pollutants (Reg 3, Part C.II.E.3.a)</u>

Solvent cold cleaners (emissions less than 2 tpy VOC) Venting of natural gas and leaks (emissions less than 2 tpy VOC)

Units with emissions less than APEN de minimis - non-criteria pollutants	(Reg	3,
Part C.II.E.3.b)		

Two (2) sulfuric acid storage tanks, 10,000 gal and 750 gal above ground (emissions less than 500 lbs/yr)

Air conditioning or ventilation systems not designed to remove air pollutants (Reg 3, Part C.II.E.3.c)

Plant air conditioning and ventilation system

Agricultural operations (Reg 3, Part C.II.E.3.g)

<u>In-house experimental and analytical laboratory equipment (Reg 3, Part C.II.E.3.i)</u>

Plant laboratory

Fuel (gaseous) burning equipment < 5 mmBtu/hr (Reg 3, Part C.II.E.3.k)

Propane portable heaters

Welding, soldering, and brazing operations using no lead-based compounds (Reg 3, Part C.II.E.3.r)

Maintenance welding machine

Chemical storage tanks or containers (Reg 3, Part C.II.E.3.n)

Small chemical tanks/containers

<u>Unpaved public and private roads - not haul roads (Reg 3, Part C.II.E.3.0)</u>

Battery recharging areas (Reg 3, Part C.II.E.3.t)

Battery storage area

Landscaping and site housekeeping devices < 10 hp (Reg 3, Part C.II.E.3.bb)

Mowers, snowblowers, etc...

Fugitive emissions from landscaping activities (Reg 3, Part C.II.E.3.cc)

Emergency events such as accidental fires (Reg 3, Part C.II.E.3.ff)

Operations involving acetylene, butane, propane, or other flame cutting torches (Reg 3, Part C.II.E.3.kk)

Portable welding torches

Chemical storage areas < 5,000 gal capacity (Reg 3, Part C.II.E.3.mm)

Oil drum storage area

Emissions of air pollutants which are not criteria or non-criteria reportable pollutants (Reg 3, Part C.II.E.3.00)

Wastewater treatment operations (no VOC emissions)
Calgon 403 (4,000 gal) and PCL-711 (2,000 gal) above ground tanks

Janitorial activities and products (Reg 3, Part C.II.E.3.pp)

Office emissions including cleaning, copying, and restrooms (Reg 3, Part C.II.E.3.tt)

Lubricating oil storage tanks < 40,000 gal (Reg 3, Part C.II.E.3.aaa)

T-5401, Turbine lube oil dual compartment storage tank (8,000 gal per compartment, above ground)

T-5401X, Turbine lube oil reservoir (4,700 gal above ground) 55106X, Turbine generator EHC lube oil tank (650 gal above ground) Two (2) combustion turbine lube oil tanks (6,000 gal each)

Fuel storage and dispensing equipment in ozone attainment areas throughput < 400 gal/day averaged over 30 days (Reg, Part C.II.E.3.ccc)

Diesel fuel tank for refueling captive vehicles (warehouse), 500 gal above ground Gasoline tank for plant vehicles (by sewage lagoons), 500 gal above ground Diesel fuel tank for refueling captive vehicles (by sewage lagoons), 500 gal above ground

T-7802, Security day tank, diesel (inside diesel building), 500 gal above ground

Storage tanks with annual throughput less than 400,0000 gal and meeting content specifications (Reg 3, Part C.II.E.3.fff)

T-8403, Diesel fuel tank for auxiliary boiler and EDG, 20,000 gal underground T-7801, Emergency security day tank, Diesel (inside diesel building), 1,000 gal vaulted above ground

T-4503, Emergency diesel firepump tank, 850 gal, above ground Emergency diesel generator tank (System 92EDG), 550 gal above ground

<u>Stationary internal combustion engines - limited hours or size (Reg 3, Part C.II.E.3.nnn)</u>

Security diesel generator set (< 737 hp and runs < 250 hrs/yr)
Station emergency generator powered by two Caterpillar diesel engines (1800 hp and runs < 100 hrs/yr)

Sandblast equipment where blast media is recycled and blasted material is collected (Reg 3, Part C.II.E.3.www)

Sandblasting machine

Nonroad engines - limited size or hours (Reg 3, Part C.II.E.3.xxx.(vi))

emergency diesel fire water pump (255 hp and runs < 850 hrs/yr)

The source also identified mobile engine tailpipe emissions and emissions from a diesel switching locomotive as insignificant activities. Emissions from these sources would not necessarily qualify them as an insignificant activity but they are not applicable to Title V permitting requirements since they are considered to be mobile sources and therefore are not subject to Title V permitting requirements. Therefore, emissions from these sources are not identified in the Operating Permit as insignificant activities.

V. Alternative Operating Scenarios:

These combustion turbines and HRSG combinations can be run in three modes: simple cycle (combustion turbine only), combined cycle (combustion turbine with HRSG) with no fuel fired in the duct burners and combined cycle (combustion turbine with HRSG) with fuel fired in the duct burners.

VI. Permit Shield:

The source identified and justified a short list of nonapplicable requirements that they wish to be specifically shielded from. The nonapplicable requirements that the source will be shielded from are as follows:

- A. 40 CFR Part 63, Subpart Q (as adopted by reference in Colorado Regulation No. 8, Part E) National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers The permit application states that this requirement is not applicable because the cooling towers do not use chromium-based water treatment chemicals. The shield was granted based on the source's justification.
- B. Colorado Regulation No. 7 (except for Section V, Paragraphs VI.B.1 and 2, and Subsection VII.C), Volatile Organic Compounds The permit application states that these regulations are not applicable because the source is not located in an ozone nonattainment area. Regulation No. 7 only applies to sources located in ozone nonattainment areas or in the Denver Metro Attainment Maintenance Area with the exception of Section V, Paragraphs VI.B.1 and 2, and Subsection VII.C which are applicable statewide.
- C. Colorado Regulation No. 7, Section V.B This requirement is not applicable as the facility is not a bulk gasoline terminal, bulk gasoline plant or gas dispensing facility.
- D. Colorado Regulation No. 7, Sections VI.B.1 and 2 These requirements are not applicable as the liquids stored in tanks greater than 40,000 gallons are exempt from the provisions of Section VI.B.2, per Section VI.B.1.a.
- E. Colorado Regulation No. 7, Section VII.C This requirement is not applicable as crude oil is not stored in tanks exceeding 40,000 gallons.

The source requested the shield for some requirements that the Division considers applicable requirements. The Specific Conditions of the permit shield are not intended to shield a source from enforcement of applicable requirements and therefore have not been included in the permit shield. Those requirements not included are as follows:

A. Colorado Regulation No. 6, Part B, Section II, Standards of Performance for New Fuel Burning Equipment - The source requested the shield from both the particulate matter requirements (Reg 6.B.II.C.2) and the opacity requirements (Reg 6.B.II.C.3). The justification for this is that the combustion turbines do not meet the definition of fuel burning equipment. Reg 6, Part B, Section II.D.3

specifically identifies combustion turbines as fuel burning equipment and provides SO₂ limits for them and this requirement is included in the construction permit (94WE609 PSD) issued for these turbines. Therefore, it is apparent that the definition of fuel burning equipment does include combustion turbines and as a result, these requirements cannot be included in the permit shield based on the source's justification.

B. Colorado Regulation No. 1, Section III.A.c, particulate matter standards for fuel burning equipment - The source requested the shield from this requirement because they believe that combustion turbines are not considered fuel burning equipment. As discussed in item A above, combustion turbines are clearly considered fuel burning equipment and therefore the permit shield cannot be granted based on the source's justification.

VII. Acid Rain Provisions:

This source is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit.

Units subject to the Acid Rain requirements are required to hold adequate SO_2 allowances and have NO_X limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain SO_2 allowances as needed. Since these units are not coal-fired boilers, they do not have any NO_X limitations.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of SO_2 , NO_X (with diluent monitor either CO_2 or O_2) and CO_2 as well as opacity and volumetric flow. Since these units burn natural gas the facility can use alternate monitoring requirements and has elected to do so. The source is not required to have an SO_2 continuous emission monitoring system (which includes a flow monitor) since the combustion turbines meet the definition of gas-fired units as identified in §72.2, but will be required to determine SO_2 emissions in accordance with Part 75 Appendix D. Also, since the combustion turbines at this facility meet the definition of gas-fired units (§72.2), they are not required to have continuous opacity monitors. These units do, however, have a continuous emission monitor to measure NO_X and CO_2 emissions.

Certification of the CEMs and/or alternate monitoring must be approved by EPA. The source has submitted Certification Application forms and Monitoring Plans for SO_2 and NO_X to the EPA.

VIII. Accidental Release Program - 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

Section 68.215(e) of the Federal Clean Air Act requires the Division to address four issues in regards to operating permit sources subject to 112(r):

1. Verify source submitted and register an RMP by deadline

EPA is in the process of setting up a Website specifically for 112(r) plans. All 112(r) sources will electronically submit their plans to this "designated central location". The Division will require sources certify in their annual compliance certification that they are/are not subject to 112(r) and they have/have not submitted a Risk Management Plan (RMP) to the designated central location by June 20, 1999. In addition, the Division will check the 112(r) website to verify that a RMP was actually submitted to the website by the deadline. Failure to submit a RMP by the June deadline by sources subject to 112(r) will be considered a permit deviation for reporting purposes under Title V.

2. Verify that source owner/operator has submitted a source certification or in its absence has submitted a compliance schedule.

As mentioned above, the Division will require that sources certify in their annual compliance certification that they are/are not subject to 112(r) and they have/have not submitted a Risk Management Plan (RMP) to the designated central location by June 20,1999. If they are subject to 112(r) but did not submit an RMP on time, a compliance schedule under the provisions of Title V must be submitted to the Division by the source. Failure to submit a RMP or a compliance schedule by the June deadline by sources subject to 112(r) will be considered a permit deviation for reporting purposes under Title V.

3. For some or all sources use one or more mechanisms such as completeness check, source audits, record review, or facility inspections to ensure permitted sources are in compliance with the requirements of this part

The Division may choose to perform any or all of the activities listed under this subsection. Although there is no specific number of such actions required in the 112(r) rule, a June 3, 1997 draft 112(r) implementation guidance from EPA

states that "Congress considered a requirement that 1.4 percent of the RMPs be audited annually, but dropped that provision."

The Division will, at a minimum, perform a "completeness check" on an unspecified number of Title V 112(r) sources. The website that EPA is in the process of developing to accept 112(r) RMP's will include software that will electronically conduct a completeness check on the RMP's. For the purposes of this operating permit, such check shall serve as the completeness check required under 68.215(e)(3). As noted in the Preamble to the final 112(r) rule (June 20, 1996 Federal Register, page 31691), "EPA agrees that the review for quality or adequacy of the RMP is best accomplished by the implementing agency..." In Colorado, the implementing agency is the U.S. EPA. If the EPA website software indicates that a source did not submit a complete plan, it will be considered a permit deviation for reporting purposes under Title V and the Division may initiate an enforcement action for failure to meet the Title V permit condition (see below). Per the Preamble (page 31691), the Division may perform the completeness checks in a timeframe consistent with the source's Title V certifications.

4. Initiate enforcement action as necessary

This refers to enforcement under Title V, not under Part 68 (112(r)). If a source fails to file a RMP or a compliance schedule by the June deadline or the EPA software indicates that the RMP is not complete, it will be considered a permit deviation for reporting purposes under Title V and the Division may initiate an enforcement action.